



raven energy ltd.



2003 Annual Report

RAVEN ENERGY LTD.

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ANNUAL GENERAL MEETING

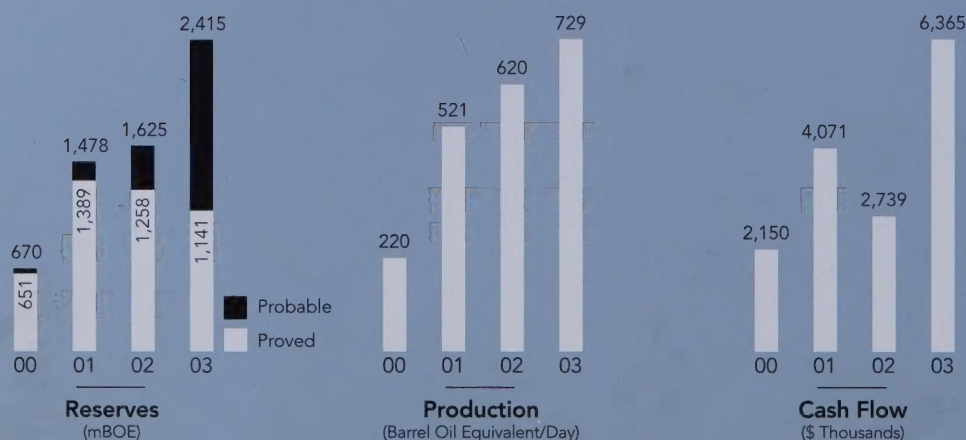
The Annual General Meeting of Raven Energy Ltd. will be held at the Westin Hotel, 320 – 4th Avenue SW at 10:00 a.m. on May 28, 2004.

ABBREVIATIONS

ARTC:	Alberta Royalty Tax Credit
bbl:	Barrel(s)
mdbl:	Thousands of barrels
BOE:	Barrel oil equivalent (6:1)
mBOE:	Thousands of barrels oil equivalent (6:1)
mcf:	Thousand cubic feet
mcf/d:	Thousand cubic feet per day
mmcf:	Million cubic feet
mmcf/d:	Million cubic feet per day
mmbtu:	Millions of British thermal units
NGL:	Natural gas liquids

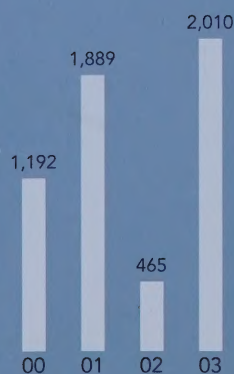
CORPORATE PROFILE

Raven Energy Ltd. is engaged in the exploration, development and production of petroleum and natural gas in Alberta. Raven's current production consists of natural gas, oil and associated liquids. We will continue to focus our exploration and development activities towards natural gas and light oil. Raven's shares are listed on the TSX Venture Exchange under the trading symbol "RVL". At year end December 31, 2003 there were 27,128,552 common shares listed.



CORPORATE HIGHLIGHTS

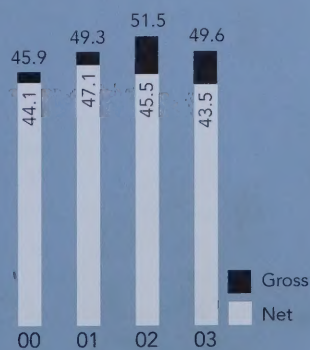
Year Ended December 31 (\$ thousands, except per share amounts)	2003	2002
Petroleum and natural gas revenue	\$ 10,059	\$ 5,298
Net income	2,010	465
Per share, basic and diluted	0.09	0.02
Cash flow from operations	6,365	2,739
Per share, basic and diluted	0.29	0.14
Net capital expenditures	12,761	5,532
Shareholders' equity	19,563	9,633
Working capital (deficiency)	1,037	(781)
Natural gas production (mcf/d)	4,035	3,612
Oil and NGL production (bbl/d)	56	18
Production (BOE/d)	729	620
Natural gas selling price (\$/mcf)	6.29	3.87
Oil and NGL selling price (\$/bbl)	38.83	30.18
Operating expenses (\$/BOE)	5.41	5.27
Cash flow netback (\$/BOE)	23.93	12.11
Proved reserves (mBOE)	1,141	1,258
Proved and probable reserves (mBOE)	2,415	1,625
F and D costs (\$/BOE) (proved and probable)	20.32	17.29
Undeveloped land		
Net acres (thousands)	43.5	45.5
Average working interest	88%	88%
Common shares		
Weighted average (millions)	21.9	19.5
Outstanding (millions)	27.1	21.0



Net Income
(\$ Thousands)



Commodity Pricing
(\$/BOE)



Undeveloped Land Holdings
(Thousands of Acres)

REPORT TO SHAREHOLDERS



We are pleased to report on the progress of our Company during 2003.

Since inception, the Company has focused on building production and reserves through drilling exploration and development prospects. Our early activities were primarily in east central Alberta where we concentrated on building an initial production base of shallow natural gas. During this time, we also acquired a considerable undeveloped land base in west central Alberta on larger impact prospects. Activities in the first half of 2003 were concentrated in east central Alberta and shifted to west central Alberta during the latter part of the year.

"Cash flow from operations increased to \$6.4 million versus \$2.7 million in 2002."

Raven participated in the drilling of 12 gross (8.6 net) wells during 2003, which included four gross (3.3 net) wells drilled in the fourth quarter of 2003. This drilling resulted in six gross (3.3 net) natural gas wells, five gross (5 net) oil wells and one gross (0.3 net) dry and abandoned well. Five natural gas wells were drilled and completed in the Viking and Inland areas of east central Alberta. The remaining natural gas well is located in the Fir area of west central Alberta. The five oil wells are all located on the Company's Ante Creek property in west central Alberta.

Production during 2003 increased 18 percent to 729 BOE per day versus 620 BOE per day in 2002. The Company received higher commodity prices during the year resulting in cash flow from operations of \$6.4 million versus \$2.7 million in 2002. Net income was \$2 million for 2003 compared to \$465 thousand in 2002. Proved and probable reserves increased from 1,625 mBOE at December 31, 2002 to 2,415 mBOE at December 31, 2003. Capital expenditures during 2003 totaled \$12.8 million, which consisted of \$5.5 million for drilling and seismic activities, \$6.2 million for completion and production equipment and \$1.1 million on land expenditures.

OUTLOOK

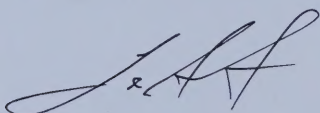
We have a solid foundation comprised of a strong financial position and an inventory of prospects which will allow us to provide for future growth. Undeveloped land holdings within Alberta totaled 49,600 gross (43,500 net) acres at an average 88 percent working interest. At year end the Company had working capital of \$1 million and \$5 million of unutilized banking facilities.

During the first quarter of 2004, Raven participated in the drilling of three gross (2 net) wells resulting in three natural gas wells. One natural gas well in east central Alberta was completed and tied in for production in late March. The other two natural gas wells in west central Alberta were completed in the first quarter and will be followed up with further drilling. Activities at Ante Creek during the first quarter of 2004 included completion of three oil wells drilled late in 2003 and the commencement of construction of facilities and pipelines to allow for production of oil and associated natural gas. Ante Creek production is currently processed through a third party facility where production is restricted due to capacity constraints at that facility. Raven is participating (30%) in the construction of a new 10 mmcf per day natural gas plant to allow for full production from the Company's existing wells and to provide for future growth. The natural gas plant and associated pipelines are anticipated to be completed by mid-year. Raven has a seven well drilling program planned for Ante Creek in 2004, commencing with three wells in the second quarter. With continued success at Ante Creek, the drilling program can be expanded on the existing undeveloped land position. In March 2004 the Company completed a private placement of 4 million shares for gross proceeds of \$7 million.

Raven has set an initial capital budget of \$15 million for 2004. These expenditures will be financed from working capital, cash flow and existing lines of credit. We will continue activities on the Viking and Inland properties, where appropriate, to maximize shallow natural gas production and associated revenue. Raven's recent exploration activities have focused on Ante Creek and other exploration projects in west central Alberta.

Raven will continue to target prospects with large reserve potential in west central Alberta that can be exploited with lower risk development drilling after initial delineation. Our goals are consistent with previous years; to achieve higher levels of production and to provide growth in shareholder value. We would like to thank our shareholders and directors for their commitment and support.

On behalf of the Board of Directors.



Laurie Smith
President & CEO
April 20, 2004

REVIEW OF OPERATIONS



OVERVIEW

Raven's activity level increased in 2003 as the Company focused on building a new core production area at Ante Creek in west central Alberta.

Raven participated in the drilling of 12 gross (8.6 net) wells during 2003. The drilling activities resulted in six gross (3.3 net) gas wells, five gross (5 net) oil wells and one gross (0.3 net) dry hole. Five of the natural gas wells were drilled in the Viking and Inland areas of east central Alberta. One gas well was drilled late in 2003 at Fir in west central Alberta. The five oil wells were drilled on the Company's Ante Creek property in west central Alberta.

Production during 2003 increased to 729 BOE per day compared to 620 BOE per day in 2002. Production was mainly natural gas, which averaged 4 mmcf per day. The Viking area contributed 3.2 mmcf per day. Oil and natural gas liquids production amounted to 56 barrels of oil per day of which Ante Creek contributed 45 barrels of light oil per day.

Cash flow netbacks increased in 2003 to \$23.93 per BOE from \$12.11 in 2002. Operating expenses were \$5.41 per BOE in 2003 compared to \$5.27 per BOE in 2002. The majority of these costs were third party processing and contract operating fees.

"Production during 2003 increased to 729 BOE per day compared to 620 BOE per day in 2002."

CAPITAL EXPENDITURES (\$ thousands)

	2003	2002
Land acquisition and retention	\$ 1,070	\$ 794
Geological and geophysical	328	438
Drilling and completion	8,485	3,199
Production equipment and facilities	2,878	1,101
Total capital expenditures	\$ 12,761	\$ 5,532



A substantial portion of the 2003 capital was invested at Ante Creek where Raven is establishing a new core production area. Expenditures in this area exceeded \$8 million including \$6.4 million for drilling, completion and recompletion activities and \$1.6 million for well equipping, oil and gas batteries and gathering systems.

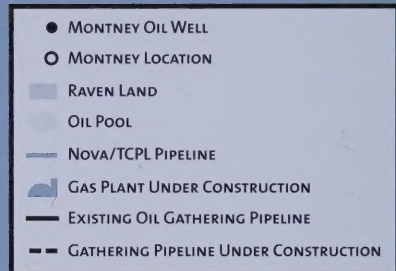
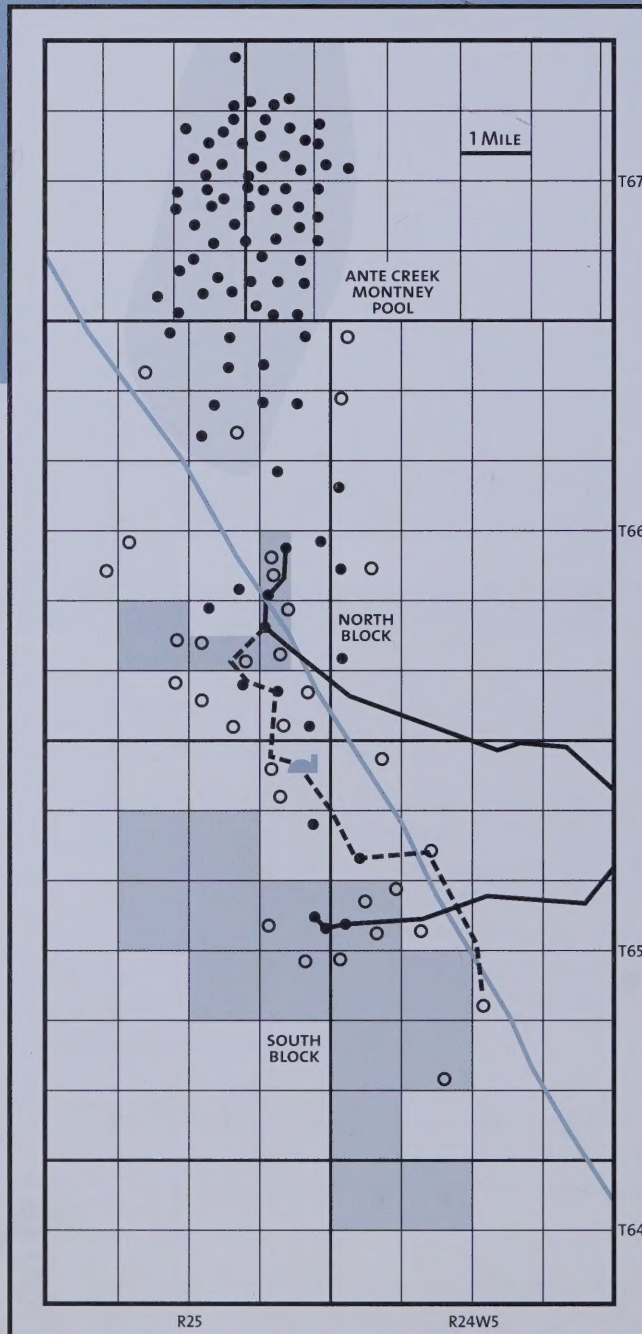
Proved plus probable reserves at year end 2003 were 2,415 mBOE compared to 1,625 mBOE for the previous year. Finding and development costs for 2003 were \$20.32 per BOE based on proved plus probable reserves. The three year average finding costs for proved plus probable reserves was \$14.73 per BOE. Capital costs of \$1.6 million were spent on infrastructure at Ante Creek in 2003. This up-front investment in infrastructure is typical of projects of this nature. Further expenditures, estimated to be between \$3 and \$4 million, are required in 2004 to construct a gas plant, build oil and gas gathering lines and to install oil production facilities. Additional development and infill wells will utilize this infrastructure reducing the capital costs necessary to bring on additional production.

EAST CENTRAL ALBERTA

The Viking area remains a core gas producing property, contributing 3,250 mcf per day of gas during 2003. Three natural gas (2 net) wells were drilled in 2003. Raven continued to recompleat uphole zones within existing wells to maximize production from this shallow gas area. Plans for 2004 include ongoing uphole gas zone completions and additional drilling.

The Company drilled two gross (1 net) wells in the Inland area in the first half of 2003. The wells were placed on production in November 2003 after the construction of a gas gathering system. Subsequent to year end, the Company (52.5%) drilled and placed another gas well on production. Raven plans further drilling and recompletion activities for the existing wells in 2004.

ANTE CREEK AREA



WEST CENTRAL ALBERTA

The most active project in west central Alberta in 2003 was Ante Creek where Raven holds a 100 percent working interest. During 2003, the Company drilled and re-entered five oil wells and resumed oil production from a previously suspended well. Three wells were drilled late in the year and subsequently placed on production in the first quarter of 2004.

In the Fir area, Raven (30%) drilled and completed a gas well which was placed on production in late February 2004. In the first quarter of 2004 the Company drilled two wells on new exploration properties. In the Sturgeon area (100%) one well was drilled on a 12 section block of land and completed as a potential natural gas well. In the Goose River area (50%) one well was drilled and also completed as a potential natural gas well. This well is located on a 10 section block of acreage. Follow-up drilling will take place next winter when frozen ground conditions will allow access.

ANTE CREEK AREA

Raven acquired a 100 percent interest in five sections of land at a crown sale in this area late in 2002. The Company also acquired a former Montney oil producer at 08-24-65-25W5M, which was drilled in 1993 and suspended in 1995. Raven placed the well on production in February 2003 and drilled and completed an offset well in the second quarter of 2003. The Montney reservoirs contain light oil (38° API) with typically high GOR's (gas to oil ratio) which require solution gas conservation to maximize production. Additional crown land was acquired in two land blocks, referred to as the North and South blocks, as shown on the inset Ante Creek map. The Company holds a 100 percent interest in 17.5 sections (11,200 acres) at March 2004.

In the North block, Raven re-entered an existing wellbore for Montney oil at 12-12-66-25W5M. The Montney zone was successfully completed and placed on production in September 2003. Late in 2003, three additional oil wells were drilled. In the first quarter of 2004 the three wells were completed and equipped for production. Raven currently has six wells producing Montney oil with three on the North block and three on the South block.

Production from Raven's oil wells was initially intermittent due to the lack of gas conservation facilities. In February 2004 the wells were tied into third party oil and gas facilities located east of Raven's properties. This allowed for the conservation and sales of the solution gas. At this time production is limited to 700 mcf per day due to capacity restraints on natural gas volumes that can be processed at these facilities. In March 2004 production from Ante Creek was 135 barrels of oil and 600 mcf of gas per day. To alleviate capacity restraints a new 10 mmcf per day gas plant is currently being constructed by an industry partner at 10-36-65-25W5M. Raven has nominated for 3 mmcf per day of gas processing capacity. This plant is expected to become operational in mid 2004 at which time Raven's wells will be re-directed to that plant.

Construction of additional oil and gas gathering pipelines is scheduled for the second quarter of 2004 to tie in production to the new gas plant. The Company is planning on drilling seven wells in this area in 2004 commencing with a three well program in the second quarter. This drilling includes one exploratory well in the South block and two infill locations on the North block. The South block is considered to be of a more exploratory nature and is largely undrilled. Most analogous pools in the area are developed on 80 acre spacing to maximize oil and gas recovery. The Company has obtained approval for 80 acre spacing on the North block and has applied for 80 acre spacing on a portion of the South block.

The Ante Creek area is very active, with other companies drilling 20 Montney test wells since early 2003 in the area offsetting Raven's land. The existing Montney pools in the general area have a large amount of oil in place (with lower primary recovery for the oil) and substantial solution gas. The Ante Creek North Triassic E (Montney) pool, located north of Raven's lands, consists of 75 producing oil wells. This pool has produced 4.5 million barrels of oil and 16.4 bcf of solution gas since initial production in 1995. The AEUB estimates that the Ante Creek North pool contains 146 million barrels of oil in place with 7.3 million barrels recoverable (approximately 5%). Natural gas in place is estimated to be 99.6 bcf with recoverable sales gas of 57.3 bcf.

Raven's activities during 2003 are beginning to positively impact production. The 2004 drilling program will delineate additional Montney oil and gas reserves. Capacity of 3 mmcf per day at the new Raven gas plant allows for ongoing development with improved economics. The new gas plant will enable full production from all Raven wells and will eliminate third party processing fees.

RESERVES SUMMARY

Raven has received its updated independent reserve evaluation report dated January 1, 2004, compliant with National Instrument 51-101 (NI 51-101) from Sproule Associates Limited. Under NI 51-101, proved reserve assignments are based on a 90 percent certainty that the total quantities recovered will equal or exceed proved reserve estimates. Proved plus probable reserves are based on a 50 percent certainty that they will equal or exceed estimates. The new standard provides for a more conservative evaluation of proved and probable reserves, particularly on new wells where production history has not yet been established. The revisions to Raven's reserves were in part due to the more stringent NI 51-101 guidelines resulting in a reduction of proved reserves and an increase in probable reserves. All reserves in this section are the Company's gross reserves before royalties using forecast prices and costs.

JANUARY 1, 2004 RESERVE SUMMARY

Reserves Category	Light Oil		Natural Gas		Natural Gas Liquids	
	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved developed producing	66.9	64.5	2,917	2,352	16.9	11.4
Proved developed non-producing	0	0.9	518	383	2.0	1.4
Proved undeveloped	143.8	126.6	1,903	1,426	21.5	14.9
Total proved	210.7	192.0	5,338	4,162	40.4	27.7
Probable	416.4	385.1	4,972	3,776	29.7	20.8
Total proved plus probable	627.1	577.2	10,311	7,937	70.1	48.5

The reserve report included capital costs of \$518,000 to place the proved developed non-producing reserves on production at Ante Creek. These funds were spent in the first quarter of 2004 to tie in the solution gas from wells in the Ante Creek area. Additional capital costs of \$2 million are required to place the proved undeveloped non-producing reserves on production. Capital costs of \$1.7 million were spent in the first quarter of 2004 to complete, equip and tie-in three wells at Ante Creek. Capital costs of \$7.7 million are required to develop probable reserves assigned to six development locations at Ante Creek.

2003 RESERVE RECONCILIATION

	Natural Gas (mmcf)		Light oil and NGL (mbbl)		Reserves (mBOE)	
	Proved	Probable	Proved	Probable	Proved	Proved and Probable
January 1, 2003	6,641	1,111	151	182	1,258	1,625
Extensions	2,102	3,326	185	409	536	1,499
Discoveries	176	102	17	9	46	72
Revisions	(2,109)	433	(81)	(154)	(432)	(514)
Production	(1,473)	—	(21)	—	(267)	(267)
January 1, 2004	5,338	4,972	251	446	1,141	2,415

Raven's proved plus probable reserves increased from 1,625 mBOE at January 1, 2003 to 2,415 mBOE at January 1, 2004. A reserve addition of 1,571 mBOE was offset by a negative revision of 514 mBOE. The largest reserve revision was in the proved category at Viking where a negative revision of 362 mBOE was realized due to production performance. This included a reclassification of 148 mBOE from proved to probable reserves. A negative revision of 84 mBOE to the probable reserves occurred at Ante Creek where an uphole oil zone was found to be non-productive upon further testing.

PRESENT VALUES OF FUTURE NET REVENUE BEFORE TAX

(\$ thousands, discounted at 10%)	2003	2002
Proved developed producing	\$ 10,179	\$ 10,284
Proved developed non-producing	1,116	956
Proved undeveloped	7,044	5,116
Total proved	\$ 18,340	\$ 16,356
Probable ⁽¹⁾	11,903	1,937
Total proved plus probable	\$ 30,243	\$ 18,293

(1) The present value of 2002 probable reserves have been reduced by 50 percent.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF DECEMBER 31, 2003

Year	Oil		Gas		NGL			Inflation Rate ⁽²⁾ (%/Yr)	Exchange Rate ⁽³⁾ (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Natural Gas ⁽¹⁾ AECO Gas Prices (\$Cdn/MMBtu)	Alliance Pipeline (\$Cdn/MMBtu)	Edmonton Pentanes Plus (\$Cdn/bbl)	Edmonton Propane (\$Cdn/bbl)	Edmonton Butanes (\$Cdn/bbl)		
2004	29.63	37.99	6.04	5.74	38.91	28.04	31.15	1.5	0.75
2005	26.80	34.24	5.36	5.06	35.07	22.56	25.52	1.5	0.75
2006	25.76	32.87	4.80	4.50	33.67	20.58	23.28	1.5	0.75
2007	26.14	33.37	4.91	4.62	34.17	20.89	23.63	1.5	0.75
2008	26.53	33.87	4.98	4.73	34.69	21.20	23.98	1.5	0.75

Thereafter: Various Escalation Rates

(1) This summary table identifies benchmark reference pricing.

(2) Inflation rates for forecasting prices and costs.

(3) Exchange rates used to generate the benchmark reference prices in this table.

FINDING AND DEVELOPMENT COSTS, PROVED AND PROBABLE

	2003	2002	2001	3 year average
Capital expenditures (\$ thousands)	\$ 12,761	\$ 5,532	\$ 7,818	\$ 26,111
Change in future capital	8,722	916	21	9,659
Total, including future capital	\$ 21,483	\$ 6,448	\$ 7,839	\$ 35,770
Reserve additions (mBOE)	1,057	373	998	2,428
Finding and development costs (\$/BOE)	\$ 20.32	\$ 17.29	\$ 7.85	\$ 14.73

Proved plus probable finding costs of \$20.32 for 2003 were high due to reserve revisions and large expenditures at Ante Creek where limited production history required a conservative approach to reserve estimation at year end. The three year finding costs for proved plus probable reserves was \$14.73 per BOE. The 2003 finding and development costs for proved reserves were very high at \$96.08 per BOE due to a negative revision offsetting the gains in reserves. Raven has reserves in the proved undeveloped category only assigned to drilled wells. Undrilled infill or development wells are treated as probable undeveloped reserves.

LAND SUMMARY

Undeveloped land expenditures in 2003 were approximately \$1.1 million. The Company acquired 12,144 net acres of petroleum and natural gas rights within Alberta at an average cost of \$72.32 per acre. An additional 536 acres were acquired by way of other acquisitions and land swaps. A total of 1,008 acres were farmed out and 160 acres were sold to industry third parties.

Raven continues to maintain a large undeveloped land base which is essential for the ongoing growth of an exploration company. The Company maintains high working interests in its undeveloped land holdings, all of which are within the Province of Alberta. Raven's undeveloped land position at year end was 49,600 gross (43,500 net) acres with an average working interest of 88 percent. The majority of Raven's undeveloped land holdings are located in west central Alberta.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis (M D & A) dated April 20, 2004 should be read in conjunction with the audited financial statements for the years ended December 31, 2003 and 2002. Additional information relating to the Company, including the Company's Annual Information Form (AIF), can be found on the SEDAR website at www.sedar.com.

"Petroleum and natural gas revenue increased 90 percent to \$10.1 million in 2003 due to increased production and commodity pricing."

Certain statements throughout this report are forward-looking statements. Readers are referred to the disclaimer regarding forward-looking information on the inside back cover of this annual report.

The M D & A contains the terms cash flow from operations and cash flow per share. Cash flow, as used by the Company, is before changes in non-cash working capital. Cash flow and cash flow per share as presented are not defined by generally accepted accounting principles (GAAP) and therefore are referred to as non-GAAP measures. These non-GAAP measures may not be comparable to the calculation of similar measures for other entities.

Where amounts are expressed on a barrel of oil equivalent basis (BOE), natural gas volumes have been converted to barrels of oil at six thousand cubic feet per barrel. BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

REVENUE AND PRODUCTION

Production	2003	2002
Natural gas (mcf/d)	4,035	3,612
Oil and NGL (bbl/d)	56	18
Oil equivalent (BOE/d)	729	620
Average Prices	2003	2002
Natural gas (\$/mcf)	6.29	3.87
Oil and NGL (\$/bbl)	38.83	30.18
Oil equivalent (\$/BOE)	37.81	23.43

Petroleum and natural gas revenue increased 90 percent to \$10.1 million in 2003 due to increased production and commodity pricing. The average sales price received increased 61 percent to \$37.81 per BOE in 2003 from \$23.43 per BOE in 2002. Natural gas prices increased 63 percent to average \$6.29 per mcf in 2003 (\$3.87 per mcf in 2002) while prices received for oil and natural gas liquids increased 29 percent to average \$38.83 per barrel.

The Company enters into physical contracts for the sale of natural gas at fixed prices and terms to protect cash flow against price volatility. These contracts are usually for periods of less than one year and would not exceed 50 percent of Raven's anticipated production volumes. The price realized on the sale of natural gas was reduced by \$0.36 per mcf in 2003 (\$0.21 per mcf in 2002) as a result of these contracts as compared to daily spot prices. Currently, the Company has contracted an average of 1.7 mmcf of natural gas per day for the period from January 1 to October 31, 2004 at an average price of approximately \$6.42 per mcf. The Company's oil and natural gas liquids are sold under 30-day "evergreen" contracts with prices based on marketing indices and adjusted for location, quality and transportation.

Production increased 18 percent to average 729 BOE per day in 2003 compared to 620 BOE per day in 2002. Increases in production were derived mainly from new wells in the Viking and Ante Creek areas offset by natural declines in the Robin and Edson areas. Natural gas production increased 12 percent to average 4,035 mcf per day in 2003 (3,612 mcf per day in 2002). Production of oil and natural gas liquids increased 211 percent from 18 barrels per day in 2002 to 56 barrels per day in 2003. Production from the Ante Creek area contributed 45 barrels per day of oil and natural gas liquids production in 2003 while natural gas liquids in 2002 were derived solely from the Edson area. Production will continue to increase in 2004 with the addition of new production in the Ante Creek area.

OPERATIONS SUMMARY

	2003			2002		
	\$000's	\$/BOE	%	\$000's	\$/BOE	%
Petroleum and natural gas revenue	\$ 10,059	\$ 37.81	100.0	\$ 5,298	\$ 23.43	100.0
Royalties, net of ARTC	1,874	7.05	18.6	962	4.26	18.2
Operating costs	1,440	5.41	14.3	1,192	5.27	22.5
Field netback	\$ 6,745	\$ 25.35	67.1	\$ 3,144	\$ 13.90	59.3
General and administrative ⁽¹⁾	299	1.12	3.0	347	1.54	6.5
Current taxes	32	0.12	0.3	5	0.02	0.1
Interest	49	0.18	0.5	53	0.23	1.0
Cash flow from operations	\$ 6,365	\$ 23.93	63.3	\$ 2,739	\$ 12.11	51.7
Stock based compensation	28	0.11	0.3	3	0.01	0.1
Depletion and depreciation	3,716	13.97	36.9	2,239	9.90	42.2
Future income taxes	611	2.30	6.1	32	0.14	0.6
Net income	\$ 2,010	\$ 7.55	20.0	\$ 465	\$ 2.06	8.8

(1) Net of non-cash general and administrative expenses.

ROYALTIES (\$ thousands)

	2003	2002
Crown royalties	\$ 1,394	\$ 392
Other royalties	829	668
Total royalties	2,223	1,060
Alberta Royalty Tax Credit	(349)	(98)
Net royalties	\$ 1,874	\$ 962

Royalties, net of ARTC, on a barrel of oil equivalent basis, increased 65 percent from \$4.26 to \$7.05 in 2003. This increase resulted from the combination of higher natural gas prices and the expiry of a crown royalty holiday in the Edson area. On a margin basis, net royalties were relatively unchanged at 18.6 percent in 2003 versus 18.2 percent in 2002. Crown royalties accounted for a larger portion of total royalties in 2003 resulting in increased Alberta Royalty Tax Credit in 2003. The Company currently receives ARTC on all its crown royalties but anticipates reaching or exceeding the maximum allowable ARTC in 2004 which will result in an increase in net royalties paid and a decline of ARTC received on a production unit basis.

Operating costs increased slightly from \$5.27 per BOE in 2002 to \$5.41 per BOE in 2003. Operating costs increased over the prior year due to higher maintenance costs and minor workovers. Operating costs are anticipated to increase in 2004 due to the higher costs associated with oil production and third party processing.

GENERAL AND ADMINISTRATIVE (\$ thousands)

	2003	2002
Gross general and administrative	\$ 541	\$ 468
Overhead recoveries	(242)	(121)
General and administrative before stock based compensation expense	299	347
Stock based compensation expense	28	3
Net general and administrative expense	\$ 327	\$ 350
Net general and administrative expense per BOE	\$ 1.23	\$ 1.55

General and administrative expenses, before overhead recovered and stock based compensation expense, increased approximately \$70,000 due mainly to additional office space acquired in 2003 but decreased on a production unit basis from \$2.07 per BOE in 2002 to \$2.03 per BOE in 2003 due to increased production levels. Overhead recovered by the Company as operator of drilling and construction activities increased in 2003 in accordance with activity. Stock options awarded to consultants are accounted for under the fair value based method utilizing assumptions as disclosed in the notes to the financial statements. Compensation expense and contributed surplus of \$28,588 have been recognized during 2003 (\$3,211 in 2002) for options granted to consultants. General and administrative expenses, net of overhead recovered, decreased from \$1.55 per BOE in 2002 to \$1.23 per BOE in 2003. Modest increases are expected in general and administrative expenses in 2004, however expenses on a production unit basis are expected to decrease with increased production.

Current taxes are composed entirely of the federal Large Corporation Tax on capital as the Company is not currently taxable on income and does not have any operations outside of Alberta. The Large Corporation Tax paid increased in 2003 due to increased equity as a result of private placements completed. Interest expense, net of interest income, of approximately \$49,000 was incurred utilizing the banking facilities at various times during 2003 (\$53,000 in 2002).

Cash flow from operations increased 132 percent to \$6.4 million from \$2.7 million in 2002 mainly as the result of increased commodity prices. On a barrel of oil equivalent basis, cash flow from operations increased 98 percent from \$12.11 per BOE in 2002 to \$23.93 per BOE in 2003. Cash flow per share increased to \$0.29 per share for 2003 versus \$0.14 per share in 2002. The weighted average number of shares outstanding in 2003 increased 12 percent to 21,929,649.

Depletion and depreciation is determined on the unit of production method based on total proved reserves (using prices and costs at the balance sheet date) with natural gas converted to a barrel equivalence using six thousand cubic feet equal to one barrel. Non-producing properties are excluded from depletion and depreciation calculations and future development costs of proved undeveloped reserves are included in depletion and depreciation calculations. The cost of non-producing properties excluded from the calculation at December 31, 2003 were \$1,793,000 (\$1,452,000 in 2002) attributable to 43,500 net acres of undeveloped land at year end. Future development costs of undeveloped reserves increased to \$2,532,000 from \$959,000 reflecting projects in progress at year end.

Depletion and depreciation increased to \$13.97 per BOE in 2003 compared to \$9.90 per BOE in 2002. Depletion and depreciation increased, on a per unit basis, due to a higher depletable base combined with the effect of reserve revisions. The provision for future abandonment and site restoration costs, included in depletion and depreciation, increased to \$0.42 per BOE from \$0.35 per BOE in 2002 as a result of the increased number of producing wells in 2003. The provision for future abandonment and site restoration is determined by management in consultation with the Company's independent engineers and is based on prevailing regulations, costs, technology and industry standards. The total future liability is estimated at \$893,000 at December 31, 2003 (\$656,000 in 2002). Current expenditures for abandonment and site restoration of producing properties were nil.

The future income tax provision for 2003 increased to approximately \$611,000 (\$32,000 in 2002) due to the increase in income. The Company's future income tax provision for 2003 includes a reduction of approximately \$267,000 due to changes in the Federal and Alberta corporate income tax rates. The Company has approximately \$12.0 million of tax pools remaining at December 31, 2003 and, depending on commodity prices and the amount and tax classification of expenditures, may be taxable on a current basis in 2004.

Net income increased to \$2.0 million versus \$0.5 million in 2002, primarily as a result of increased natural gas prices partially offset by increased depletion and future income tax provisions. Earnings per share increased to \$0.09 per share versus \$0.02 per share in 2002.

RECENT ACCOUNTING PRONOUNCEMENTS

OIL AND GAS ACCOUNTING – FULL COST

The CICA recently issued Accounting Guideline No. 16 which establishes standards for the application of the full cost method of accounting for oil and gas exploration, development and production activities. The guideline establishes a new cost centre impairment test (ceiling test) for oil and gas assets. Application of the new guideline is required for fiscal years beginning on or after January 1, 2004. Adoption of this standard would not have had any impact of the Company's financial statements for the year ended December 31, 2003.

ASSET RETIREMENT OBLIGATIONS

The CICA recently issued Section 3110 which changes the method of accruing for future site restoration and abandonment liabilities. The standard requires the recording of the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a capitalization of the corresponding amount to the asset's carrying value. This asset retirement cost is then expensed, using a systematic and rational method, over the estimated useful life of the related asset. This standard is effective January 1, 2004 and requires retroactive restatement of the Company's financial statements upon adoption. Raven does not anticipate that adoption of this standard will have a material adverse impact on its financial position or results of operations.

STOCK BASED COMPENSATION AND OTHER STOCK BASED PAYMENTS

In the fall of 2003, the CICA amended Section 3870 to require recognition of expense, based on the fair value method, for all employee stock-based compensation transactions for fiscal years beginning on or after January 1, 2004. The recommendations of this Section are retroactive to awards granted on or after January 1, 2002. The Company has elected for 2003 to continue to account for its stock based compensation plan for directors, officers and employees whereby compensation cost is not recognized in the financial statements for stock options issued at market value. Application of the amended Section in 2004 will result in the restating of the 2003 stock based compensation expense by \$192,683 as disclosed in Note 5 (d) to the audited financial statements.

LIQUIDITY AND CAPITAL RESOURCES

Capital expenditures of \$12.8 million were financed through a combination of cash flow, the proceeds of private placements completed during the year and the utilization of working capital. In September 2003 the Company issued 2,000,000 common shares through a private placement for gross proceeds of \$2.6 million. The issue was equally composed of common shares and flow-through common shares. In December 2003, the Company completed a private placement of 3,750,000 common shares for gross proceeds of \$6 million. The total outstanding common shares were 27,128,552 at December 31, 2003.

At December 31, 2003 the Company had working capital of approximately \$1 million and unutilized bank facilities. The current bank facilities are \$5 million subject to the annual review of current activities and reserves. Banking facilities available to the Company are in part determined by the borrowing base of the Company. This borrowing base may be reduced by several factors including a material decline in commodity prices or revisions in reserve estimates, thereby reducing the bank credit available to the Company.

In March 2004 the Company completed a private placement of 4,000,000 common shares for gross proceeds of \$7 million. The 2004 capital budget has been approved at \$15 million and will be funded through cash flow, the recently completed private placement and utilization of credit facilities. Raven's cash flow and earnings are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond the control of the Company. Therefore, the Board of Directors reviews the capital budget throughout the year and adjusts it according to current industry conditions including financing capabilities at that time.

BUSINESS RISKS

Exploration, development and production of petroleum and natural gas involve many risks that even the combination of experience and careful evaluation may not be sufficient to overcome. Utilizing highly skilled professionals, focusing in areas where the Company has existing knowledge and expertise or access to such expertise, using up to date technology, and controlling costs to maximize margins, mitigate these risks. The Company maintains a comprehensive insurance program that insures liability and property consistent with industry practice. The program is designed to mitigate risks and protect against significant loss. However, the Company is not fully insured against all these risks, nor are all such risks insurable.

Financial risks include exposure to fluctuation in commodity prices, currency exchange rates, and interest rates. To mitigate commodity risk, the Company maintains direct marketing control over its production. The Company enters into physical contracts for the sale of natural gas at fixed prices and terms and currently has fixed pricing arrangements as disclosed earlier. Although not currently utilized, the Company may institute financial hedging techniques for interest rates, currency exchange rates and commodity prices. If utilized, such transactions would be subject to certain limits on term and amount as established by the Board of Directors.

SUMMARY OF QUARTERLY RESULTS

(\$ thousands, except where indicated) (unaudited)

2003 Quarter Ended	March 31	June 30	September 30	December 31
Revenue before royalties	\$ 3,066	\$ 2,230	\$ 2,640	\$ 2,122
Cash flow from operations	1,945	1,328	1,702	1,391
Per basic share	0.09	0.06	0.08	0.06
Per diluted share	0.09	0.06	0.08	0.06
Net income (loss)	737	759	664	(150)
Per basic share	0.03	0.04	0.03	(0.01)
Per diluted share	\$ 0.03	\$ 0.04	\$ 0.03	\$ (0.01)
Production (BOE/d)	782	681	793	660
2002 Quarter Ended	March 31	June 30	September 30	December 31
Revenue before royalties	\$ 1,127	\$ 1,230	\$ 1,158	\$ 1,784
Cash flow from operations	517	593	592	1,037
Per basic share	0.03	0.03	0.03	0.05
Per diluted share	0.03	0.03	0.03	0.05
Net income	7	69	61	328
Per basic share	0.00	0.00	0.00	0.01
Per diluted share	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.01
Production (BOE/d)	631	615	611	622

Quarterly revenues in 2003, as compared to the same periods in 2002, increased to reflect higher production volumes and commodity pricing. Quarterly net income also increased accordingly until the final quarter of 2003 when non-cash provisions for depletion and future income taxes increased as a result of reserve revisions.

SELECTED ANNUAL INFORMATION (\$ thousands, except per share)

	2003	2002	2001
Revenue before royalties	\$ 10,059	\$ 5,298	\$ 6,228
Cash flow from operations	6,365	2,739	4,071
Per basic share	0.29	0.14	0.23
Per diluted share	0.29	0.14	0.23
Net income	2,010	465	1,889
Per basic share	0.09	0.02	0.11
Per diluted share	0.09	0.02	0.11
Capital expenditures	12,761	5,532	7,818
Total assets	30,359	15,206	15,219
Working capital (deficiency)	1,037	(781)	549
Long term financial liabilities			
Future abandonment and site restoration	258	146	67
Future income taxes	\$ 4,352	\$ 3,419	\$ 3,087
Production (BOE/d)	729	620	521

NET ASSET VALUE (\$ thousands, except per share)

	2003	2002
Present value of appraised reserves ^{(1) (2)}	\$ 30,243	\$ 18,293
Appraised value of undeveloped land ⁽³⁾	2,467	1,926
Working capital (deficiency)	1,037	(781)
Net asset value ⁽⁴⁾	\$ 33,747	\$ 19,438
Net asset value per share ⁽⁵⁾	\$ 1.24	\$ 0.92

(1) Proved plus probable reserves discounted at 10 percent before income taxes used for 2003.

(2) Proved plus half probable reserves discounted at 10 percent before income taxes used for 2002.

(3) Based on independent appraisals at January 1, 2004 and 2003.

(4) Excludes the value of proprietary seismic and other assets.

(5) 27,128,552 shares outstanding at December 31, 2003 (21,028,552 in 2002).

MANAGEMENT'S REPORT

The accompanying financial statements and all information in the Annual Report are the responsibility of management. The financial statements have been prepared by management in accordance with the accounting policies in the notes to the financial statements. When necessary, management has made informed judgments and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality, and are in accordance with Canadian generally accepted accounting principles (GAAP) appropriate in the circumstances. The financial information elsewhere in the Annual Report has been reviewed to ensure consistency with that in the financial statements.

Management has prepared Management's Discussion and Analysis (MD&A). The MD&A is based upon the Company's financial results prepared in accordance with Canadian GAAP. The MD&A compares the audited financial results for the twelve months ended December 31, 2003 to December 31, 2002.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are properly authorized, assets are safeguarded and financial records properly maintained to provide reliable information for the preparation of financial statements.

KPMG LLP, an independent firm of Chartered Accountants, was engaged, as approved by a vote of shareholders at the Company's most recent annual general meeting, to audit the financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion.

The Audit Committee of the Board of Directors has discussed the financial statements, including the notes thereto, with management and external auditors. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.



Laurie Smith
President & CEO
April 13, 2004



Sharon Supple
Chief Financial Officer

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the balance sheets of Raven Energy Ltd. as at December 31, 2003 and 2002 and the statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

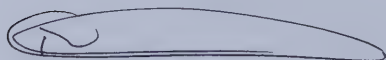
Chartered Accountants
Calgary, Canada
April 13, 2004

BALANCE SHEETS

December 31	2003	2002
Assets		
Current assets		
Cash and term deposits	\$ 4,619,820	\$ 63,846
Accounts receivable	2,521,631	1,018,578
Prepaid expenses and deposits	81,776	144,679
	7,223,227	1,227,103
Petroleum and natural gas properties <i>[note 2]</i>	23,135,861	13,979,161
	<u>\$ 30,359,088</u>	<u>\$ 15,206,264</u>
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$ 6,185,865	\$ 2,007,671
Future abandonment and site restoration costs	258,300	146,100
Future income taxes <i>[note 4]</i>	4,352,000	3,419,310
Shareholders' equity		
Share capital <i>[note 5]</i>	14,344,332	6,452,738
Contributed surplus	31,799	3,211
Retained earnings	5,186,792	3,177,234
	19,562,923	9,633,183
Subsequent event <i>[note 5 (c)]</i>		
	<u>\$ 30,359,088</u>	<u>\$ 15,206,264</u>

See accompanying notes to financial statements.

Approved on behalf of the Board



David H. Erickson
Director



John D.G. van der Lee
Director

STATEMENTS OF INCOME AND RETAINED EARNINGS

Years ended December 31	2003	2002
Revenue		
Petroleum and natural gas	\$ 10,058,901	\$ 5,298,076
Royalties, net of ARTC	(1,874,373)	(961,801)
	8,184,528	4,336,275
Expenses		
Operating	1,440,368	1,192,317
General and administrative	326,939	349,767
Interest	48,746	52,825
Depletion and depreciation	3,716,080	2,238,740
	5,532,133	3,833,649
Income before income taxes	2,652,395	502,626
Income taxes [note 4]		
Current	31,797	5,465
Future	611,040	31,695
	642,837	37,160
Net income	2,009,558	465,466
Retained earnings, beginning of year	3,177,234	2,711,768
Retained earnings, end of year	\$ 5,186,792	\$ 3,177,234
Earnings per share – basic and diluted	\$ 0.09	\$ 0.02
Weighted average number of common shares outstanding – basic	21,929,649	19,526,269
Weighted average number of common shares outstanding – diluted	22,289,342	19,977,971

See accompanying notes to financial statements.

STATEMENTS OF CASH FLOWS

Years ended December 31	2003	2002
Cash provided by (used in):		
Operating activities		
Net income	\$ 2,009,558	\$ 465,466
Items not involving cash:		
Stock based compensation [note 5(d)]	28,588	3,211
Depletion and depreciation	3,716,080	2,238,740
Future income taxes	611,040	31,695
Funds flow from operations	6,365,266	2,739,112
Change in non-cash working capital	(90,704)	312,036
	6,274,562	3,051,148
Financing activities		
Issue of share capital, net of issuance costs	8,213,244	1,462,562
Change in non-cash working capital	1,217	10,036
	8,214,461	1,472,598
Investing activities		
Petroleum and natural gas properties	(12,760,580)	(5,531,740)
Change in non-cash working capital	2,827,531	(1,072,275)
	(9,933,049)	(6,604,015)
Increase (decrease) in cash and term deposits	4,555,974	(2,080,269)
Cash and term deposits, beginning of year	63,846	2,144,115
Cash and term deposits, end of year	\$ 4,619,820	\$ 63,846
Supplemental cash flow information:		
Cash received (paid) during the year for:		
Interest expense	\$ (58,114)	\$ (41,789)
Income taxes	\$ (31,797)	\$ 145,638

See accompanying notes to financial statements.

NOTES TO FINANCIAL STATEMENTS

Years ended December 31, 2003 and 2002

Raven Energy Ltd. (the "Company") was incorporated under the Business Corporations Act (Alberta) on June 15, 1998. The principal business activities of the Company are the exploration, development and production of petroleum and natural gas in Alberta.

1. SIGNIFICANT ACCOUNTING POLICIES:

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles. The principal accounting policies followed by the Company are summarized below:

(a) Petroleum and natural gas properties:

ii) Petroleum and natural gas properties

The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized and accumulated in a single cost center representing the Company's activity undertaken exclusively in Canada. Such costs include land acquisition costs, geological and geophysical expenses, lease rental costs on non-producing properties, costs of drilling both productive and non-productive wells, related plant and production equipment costs, and administration costs directly related to these activities.

The provision for depletion and depreciation is determined on the unit-of-production method based on the estimated gross proven reserves as determined by independent engineers. Petroleum and natural gas reserves and production are converted into equivalent units based upon relative energy content. Costs associated with the acquisition and evaluation of unproved properties are excluded from amounts subject to depletion until such times as the properties are proved or become impaired.

The capitalized costs less accumulated depletion and depreciation are limited to an amount equal to the estimated future net revenue from proven reserves (based on prices and costs at the balance sheet date) plus the unimpaired cost of non-producing properties less estimated future administrative expenses, development costs, financing costs and income taxes.

Proceeds from the sales of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

Future abandonment and site restoration costs

Estimated future abandonment and site restoration costs are provided for over the life of the proven reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Company's independent engineers based on current regulations, costs, technology and industry standards. The annual charge is included in depletion and depreciation expense and actual abandonment and site restoration expenditures are charged to the accumulated provision account as incurred.

ii) Joint activities

The Company conducts some exploration and production activities jointly with others and accordingly these statements reflect only the Company's proportionate interest in such activities.

(b) Income taxes:

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities), and are measured using the currently enacted, or substantively enacted, tax rates and laws expected to apply when these differences reverse. Income tax expense is the sum of the Company's provision for current income taxes and the difference between opening and ending balances of the future income tax assets and liabilities.

(c) Flow-through shares:

The Company has financed a portion of its petroleum and natural gas exploration activities with flow-through share issues. The exploration and development expenditures funded by flow-through share expenditures are renounced to investors in accordance with tax legislation. The estimated value of the tax pools foregone is reflected as a reduction in share capital with a corresponding increase in future income taxes.

(d) Stock based compensation:

The Company has an equity incentive plan, which is described in Note 5 (d).

The Company has elected to continue to account for its stock-based compensation plan for directors, officers and employees whereby compensation cost is not recognized in the financial statements for stock options when issued at market value. Any consideration received on exercise of the stock options is credited to share capital.

Stock option awards to consultants are accounted for under the fair value based method, and such awards result in a compensation expense in the period that the benefit relates to.

(e) Per share amounts:

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the year. Diluted per share amounts are calculated based on the treasury stock method, which assumes that any proceeds obtained on the exercise of options would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

(f) Measurement uncertainty:

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and the provision for future abandonment and site restoration costs are based on estimates. The ceiling test is based on such factors as estimated proven reserves, production rates, petroleum and natural gas prices and future costs. By their nature, these estimates are subject to measurement uncertainty and changes in these estimates may impact the financial statements of future periods.

(g) Financial instruments:

The Company periodically uses certain financial instruments to hedge its exposure to commodity price fluctuation on a portion of its petroleum and natural gas sales. Gains and losses on these transactions are reported as adjustments to revenue when the related production is sold.

(h) Foreign currency translation:

Monetary items denominated in foreign currency are translated to Canadian dollars at the rate in effect at the balance sheet date and non-monetary items are translated at rates of exchange in effect when the assets were acquired or obligations incurred. Revenue and expenses are translated at rates in effect at the time of the transactions. Foreign exchange gains and losses are included in income.

2. PETROLEUM AND NATURAL GAS PROPERTIES:

	2003	2002
Petroleum and natural gas properties, at cost	\$ 30,550,045	\$ 17,789,465
Accumulated depletion and depreciation	7,414,184	3,810,304
	<u>\$ 23,135,861</u>	<u>\$ 13,979,161</u>

Costs of unproved properties excluded from costs subject to depletion and depreciation at December 31, 2003 were approximately \$1,793,000 (2002 – \$1,452,000). Future development costs of proven undeveloped reserves of \$2,532,000 (2002 – \$959,000) were included in costs subject to depletion and depreciation.

Estimated future abandonment and site restoration costs to be accrued over the remaining life of the proved reserves are approximately \$635,000 (2002 – \$510,000).

3. BANK FACILITY:

The Company has access to a demand revolving facility of \$5,000,000 from a Canadian chartered bank. The credit facility bears interest at bank prime rate plus 0.50% per annum and is secured by a general security agreement constituting a first ranking security interest in all personal property and a first ranking charge on all real property. As at December 31, 2003, the line of credit was unused.

4. INCOME TAXES:

- (a) The provision for income taxes differs from the amounts which would be obtained by applying the combined federal and provincial income tax rate as follows:

	2003	2002
Income tax rate	40.62%	42.12%
Expected income tax provision	\$ 1,077,403	\$ 211,706
Increase (decrease) in taxes resulting from:		
Non-deductible crown payments	552,803	206,369
Resource allowance	(631,025)	(313,066)
Alberta Royalty Tax Credit	(134,507)	(41,234)
Future income tax rate reduction	(267,461)	(36,221)
Large corporation tax	31,797	5,465
Other	13,827	4,141
	<u>\$ 642,837</u>	<u>\$ 37,160</u>

- (b) The components of the Company's net future income tax liability at December 31, 2003 and 2002 are as follows:

	2003	2002
Petroleum and natural gas properties	\$ (4,593,753)	\$ (3,488,434)
Future abandonment and site restoration	87,900	46,153
Share issue costs	153,853	22,971
	<u>\$ (4,352,000)</u>	<u>\$ (3,419,310)</u>

5. SHARE CAPITAL:

(a) Authorized:

The authorized share capital consists of an unlimited number of common shares and an unlimited number of preferred shares, issuable in series. No preferred shares have been issued.

(b) Common shares issued:

	2003		2002	
	Number of Shares	Amount	Number of Shares	Amount
Balance, beginning of year	21,028,552	\$ 6,452,738	19,361,886	\$ 5,290,306
Issued on exercise of stock options	350,000	35,000	—	—
Private placements for cash	5,750,000	8,600,000	1,666,666	1,500,000
Tax effect of flow-through shares	—	(478,390)	—	(315,900)
Share issue costs	—	(421,756)	—	(37,438)
Tax effect of share issue costs	—	156,740	—	15,770
Balance, end of year	27,128,552	<u>\$14,344,332</u>	21,028,552	<u>\$ 6,452,738</u>

(c) Private placements:

On March 24, 2004 the Company completed a private placement of 4,000,000 common shares at a price of \$1.75 per share for gross proceeds of \$7,000,000.

On December 18, 2003 the Company completed a private placement of 3,750,000 common shares at a price of \$1.60 per share for gross proceeds of \$6,000,000.

On September 22, 2003 the Company completed a private placement of 1,000,000 units at a price of \$2.60 per unit for gross proceeds of \$2,600,000. Each unit consisted of one common share and one flow-through common share. Directors and officers of the Company subscribed for 94,000 units for consideration of \$244,400. Total flow-through share issues during the year were \$1,300,000 of which \$1,000,000 remains to be expended on qualifying expenditures by December 31, 2004.

On November 25, 2002 the Company completed a private placement of 833,333 units at a price of \$1.80 per unit for gross proceeds of \$1,500,000. Each unit consisted of one common share and one flow-through common share. Directors and officers of the Company subscribed for 164,145 units for consideration of \$295,461.

(d) Stock option plan:

The Company has a stock option plan authorizing the grant of options to acquire shares to designated participants (being directors, officers, employees or consultants). Under terms of the plan the Company may grant options to acquire a maximum number of shares equal to ten percent of the total issued and outstanding shares of the Company. The aggregate number of options that may be granted to any one individual must not exceed five percent of the total issued and outstanding shares. Options are granted at exercise prices equal to the market value of the shares at the date of grant and are granted for a five year term. Options granted to officers and directors vest immediately. The vesting periods for options granted to employees and consultants are determined by the Board at the time of the specific grant.

The following table summarizes the changes in the Company's stock option plan:

	2003		2002	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Balance, beginning of year	800,000	\$ 0.55	775,000	\$ 0.56
Granted	450,000	\$ 1.00	50,000	\$ 0.80
Exercised	(350,000)	\$ 0.10	—	—
Forfeited	—	—	(25,000)	\$ 1.29
Balance, end of year	900,000	\$ 0.95	800,000	\$ 0.55
Options exercisable at end of year	850,001	\$ 0.95	750,000	\$ 0.53

The following table summarizes information about the stock options outstanding at December 31, 2003:

Options outstanding			Options exercisable		
Range of exercise prices	number outstanding	weighted average remaining contractual life (years)	weighted average exercise price	number exercisable	weighted average exercise price
\$0.10-0.49	200,000	0.7	\$0.42	200,000	\$0.42
\$0.50-0.99	50,000	3.8	\$0.80	33,334	\$0.80
\$1.00-1.50	650,000	3.6	\$1.12	616,667	\$1.13
\$0.10-1.50	900,000	2.9	\$0.95	850,001	\$0.95

On January 8, 2003 the Company granted 400,000 options to officers and directors and 50,000 options to a consultant to the Company. The options are exercisable at a price of \$1.00 per share and expire five years from the date of grant. The fair value of the options granted was estimated on the date of the grant using the Black Scholes option pricing model with the following weighted average assumptions: zero dividend yield, expected volatility of fifty percent, risk-free interest rates of four percent and expected life of five years. The weighted average fair market value of options granted during 2003 was \$0.48 per option (2002 – \$0.39 per option).

Compensation expense and contributed surplus of \$28,588 have been recognized during 2003 (2002 – \$3,211) for options granted to consultants. Had the Company accounted for options granted to directors, officers and employees using the fair value method, net income for the year ended December 31, 2003 would have decreased by \$192,683 to \$1,816,875 and earnings per share, both basic and diluted, would have decreased by \$0.01 per share to \$0.08 per share.

6. RISK MANAGEMENT:

(a) Interest rate risk:

The Company is exposed to interest rate fluctuations on any outstanding bank indebtedness.

(b) Credit risk:

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's petroleum and natural gas are subject to an internal credit review to minimize the risk of non-payment.

(c) Commodity risk:

The Company has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company has entered into fixed priced sales contracts for a portion of its future natural gas production resulting in an average contracted volume of 1.7 million cubic feet per day for the period January 1, 2004 to October 31, 2004 at a weighted average contract price of \$6.42 per thousand cubic feet.

(d) Fair value of financial instruments:

Financial instruments of the Company consist of cash and term deposits, accounts receivable, prepaid expenses and deposits, accounts payable, and accrued liabilities. At December 31, 2003 there are no significant differences between the carrying value of such instruments reported on the balance sheet and their estimated market value.

CORPORATE INFORMATION

Directors

David H. Erickson
J. Reid Hutchinson*
Laurie J. Smith*
John D.G. van der Lee*

Officers

Laurie J. Smith
President & CEO
Sharon A. Supple
Chief Financial Officer
David H. Erickson
Vice-President, Operations
Daniel G. Kolibar
Secretary

Registered Office

Suite 1000,
400 – 3rd Avenue S.W.
Calgary, Alberta T2P 4H2

Head Office

Suite 400,
839 – 5th Avenue S.W.
Calgary, Alberta T2P 3C8
Tel: (403) 264-9058

Legal Council

Borden Ladner Gervais LLP
Calgary, Alberta

Banker

Royal Bank Of Canada
Calgary, Alberta

Transfer Agent & Registrar

CIBC Mellon Trust Company of Canada
Calgary, Alberta

Auditors

KPMG LLP
Calgary, Alberta

Listed

TSX Venture Exchange
Common Share Symbol: RVL

Web Site

www.ravenenergy.com

*Member, Audit Committee

Certain statements throughout this annual report, including management's assessment of the Company's future plans and operations are forward-looking statements that involve substantial known and unknown risks and uncertainties. These risk and uncertainties include, among others: risks associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, uncertainty of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources. Accordingly, events or circumstances could cause actual results to differ materially from those predicted.



raven energy ltd. Suite 400, 839 – Fifth Avenue SW, Calgary, Alberta, Canada T2P 3C8